DESTEC

ENERGY

DESTEC ENERGY, INC.
2500 CITYWEST BLVD., SUITE 150
P.O. BOX 4411
HOUSTON, TEXAS 77210-4411
(713) 735-4000

RECEIVED

SEP 9 1994

Bureau of
Air Regulation

September 7, 1994

Mr. Bill Proses
Florida Department of Environmental Protection
Southwest District
3804 Coconut Palm Drive
Tampa, Florida 33619

RE: **Zero Liquid Discharge System - Initial Firing**
Permit No. AC53-230744 and IC53-221795
Tiger Bay Limited Partnership
Tiger Bay Cogeneration Facility

Dear Mr. Proses,

On September 1, 1994, the initial natural gas firing of the zero liquid discharge system occurred.

Should you have any questions, please feel free to contact me at (713) 735-4087.

Sincerely,

Robert S. Chatham, P.E.
Senior Environmental Engineer

RSC:kro

cc: Teresa Heron, FDEP - Tallahassee
George Sharrock, FDEP - Tampa

G:\1253\CORRESPO\proses5.rsc

A SUBSIDIARY OF THE DOW CHEMICAL COMPANY

DEP ROUTING AND TRANSMITTAL SLIP

TO: (NAME, OFFICE, LOCATION)

1. Mike Harley
2. _____

3. _____
4. _____
5. _____

PLEASE PREPARE REPLY FOR:

_____ SECRETARY'S SIGNATURE

_____ DIV/DIST DIR SIGNATURE

_____ MY SIGNATURE

_____ YOUR SIGNATURE

_____ DUE DATE _____

ACTION/DISPOSITION

_____ DISCUSS WITH ME

_✓__ COMMENTS/ADVISE

_____ REVIEW AND RETURN

_____ SET UP MEETING

_✓__ FOR YOUR INFORMATION

_____ HANDLE APPROPRIATELY

_____ INITIAL AND FORWARD

_____ SHARE WITH STAFF

_____ FOR YOUR FILES

COMMENTS:

Re: Emission Test Protocol

RECEIVED

SEP 15 1994

Emissions Monitoring

Mike,
Test Protocol looks good.
Yogesh

Is
Db
duct
Luener

MAX
MUST
TEST
HERE

MAX
MUST
TEST
HERE

Otherwise it is a violation!

FROM: Louisa   **DATE:** 9/14   **PHONE:** _____

DEP 15-026 (12/93)

DESTEC ENERGY, INC.
2500 CITYWEST BLVD., SUITE 150
P.O. BOX 4411
HOUSTON, TEXAS 77210-4411
(713) 735-4000

September 7, 1994

Mr. Bill Proses
Florida Department of Environmental Protection
Southwest District
3804 Coconut Palm Drive
Tampa, Florida 33619

RE: CEMS Certification and Source Testing Date
Permit No. AC53-214903 and PSD-FL-190
Tiger Bay Limited Partnership
Tiger Bay Cogeneration Facility

Dear Mr. Proses,

On behalf of Tiger Bay Limited Partnership, we are enclosing the initial source testing and continuous emission monitoring certification protocol. We plan to certify the continuous emission monitoring system (CEMS) and perform the initial compliance source testing between September 19 and 25.

Should you have any questions, please feel free to contact me at (713) 735-4087.

Sincerely,

Robert S. Chatham, P.E.
Senior Environmental Engineer

RSC:kro
Enclosure

cc: :Teresa Heron,¹ FDEP - Tallahassee

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EMISSION TEST PROTOCOL
FOR
TIGER BAY COGENERATION
PROJECT
FORT MEADE, FLORIDA

Prepared for:

DESTEC Engineering, Inc.
2500 City West Boulevard, Suite 150
Houston, Texas 77042

Prepared by:

ENVIRONMENTAL SCIENCE & ENGINEERING, INC.
P.O. Box 1703
Gainesville, Florida 32602

ESE No. 3941227-0100-3100

September 1994

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1.0 INTRODUCTION

Environmental Science & Engineering (ESE), Inc. is under contract to Destec Engineering (Destec) to provide emissions testing support for emissions compliance sampling for a stationary combustion turbine (CT) recently constructed in Fort Meade, Florida. The combustion turbine facility is the Tiger Bay Cogeneration Project. This document is the test protocol for the initial emissions compliance test program as required by the Florida Department of Environmental Regulation (FDER) and as required by Federal New Source Performance Standards (NSPS) as well as for the initial continuous emissions monitoring system (CEMS) certification by relative accuracy test audit (RATA). The Florida Department of Environmental Protection (FDEP) construction permit for the facility is AC53-214903/PSD-FL-190.

The combustion turbine is a combined cycle General Electric Model (GE) PG7221FA (Frame 7FA) equipped with dry-low NO_x burners. The CT uses premix flame technology to control emissions of nitrogen oxides (NO_x) rather than conventional water injection technology. The CT is capable of firing either natural gas or liquid distillate fuel; however, at present the unit is only equipped to fire natural gas. The unit also includes a natural gas fired duct burner just prior to the heat recovery steam generation (HRSG) system for supplemental heat input. All emissions testing will take place at the combined cycle exhaust stack.

There are two phases to the scope of work for the test program including conducting CEM certifications by relative accuracy test audit (RATA) for the O_2 and NO_x analyzers as well as conducting initial compliance testing. For this test program, the tests will be conducted simultaneously.

Compliance testing includes conducting tests to satisfy the FDEP permit emissions limits as well as Federal NSPS initial performance testing requirements (40CFR60, Subpart GG). The permit conditions require testing for NO_x, CO, VOC, VE and particulate matter as well as for diluent oxygen and volumetric flowrate. The tests for initial permit compliance demonstration are required to be conducted at between 95% and 100% of maximum achievable load (ie peak load) for the given ambient conditions during the tests. A full set of testing is required while firing only the turbine and also while firing the duct burner at maximum load (6 total full load runs - 3 at each condition). All tests will be conducted at the combined cycle stack. If possible, the conditions will be alternated in order to obtain the most comparable results so that Run 1 for the turbine only can be most directly correlated to Run 1 while firing the duct burner, etc.

In addition to the full load testing required for the duct burner and for the turbine to demonstrate compliance with the FDEP permit emission limits, the unit is also subject to Federal NSPS (Subpart GG) initial performance tests at four discrete loads (for the turbine only.) This testing is conducted for O_2 and NO_x only. The permit compliance tests at maximum load for the turbine will constitute one of the test conditions. Three additional load conditions will then be required to be conducted over the normal operating range of the turbine. Three test runs will be conducted at each condition using EPA Method 20.

Compliance with the sulfur dioxide and sulfuric acid mist requirements of the permit will be demonstrated by fuel analysis due to the low concentrations expected. It should be noted that fuel analysis does not provide insight into the sulfuric acid mist emissions, nor is it practical to conduct EPA Method 8 sampling at the low levels of H_2SO_4 expected. ESE will therefore use emissions factors combined with the fuel analysis data to demonstrate compliance with these limits as we have done in the past for FDEP.

Currently, it is planned for Destec to collect the natural gas fuel samples and have them analyzed by an independent commercial laboratory.

The FDEP permit requires that NO_X and O_2 CEMS be installed for the unit for surveillance purposes. RATA certification of the NO_X and diluent O_2 CEMS will be conducted using EPA Method 20 and the procedures given for RATA in Performance Specifications 2 and 3 of 40CFR60, Appendix B. Destec will provide the data for the 7 day drift tests for the analyzers. The results of the 7 day drift test will be incorporated into the CEM Certification Test Report.

The test methods which will be used for this test program are listed briefly below:

EPA Method 1: Determination of Sampling point location for particulate and velocity traverses.

EPA Method 2: Determination of velocity and volumetric flow rate from stationary sources using calibrated type K thermocouples and type S pitot tubes.

EPA Method 3: Determination of flue gas molecular weight, O_2 and CO_2 using an ORSAT analyzer.

EPA Method 3A: Continuous determination of O_2 and CO_2 using a paramagnetic and a non-dispersive infrared analyzer, respectively.

EPA Method 4: Determination of flue gas moisture content.

EPA Method 5: Determination of particulate matter emissions from stationary sources.

EPA Method 9: Determination of opacity as visible emissions (VE) by a qualified observer.

EPA Method 10: Continuous determination of CO using a gas filter correlation/nondispersive infrared analyzer (GFC/NDIR).

EPA Method 18: Determination of speciated gaseous organic compounds by analysis using gas chromatography. (optional - depending on the Method 25A result)

EPA Method 20: Determination of nitrogen oxides using continuous emissions monitoring techniques with a chemiluminescent analyzer.

EPA Method 25A: Continuous determination of volatile organic compounds as total gaseous organic concentration using a flame ionization analyzer.

All procedures and quality control guidelines specified in the appropriate methods will be strictly followed during the test program, in addition to ESE's more stringent internal quality control standards.

Note that EPA Method 17 may be substituted for EPA Method 5 depending on the temperature of the flue gas. EPA Method 18 will only be used to determine methane

content in the gas for subtraction from the Method 25A result if the Method 25A result exceeds the emission limit. Triplicate test runs will be performed at each condition. The emissions limits for the combustion turbine and duct burner are included in Table 1 in the facility permit included in Appendix A.

The emissions tests will be coordinated for Destec by Mr. Scott Kicker. Bill Mayhew will be the ESE project manager for the test program and will be on site during the tests as the field team leader and instrument operator.

FDEP has been notified in advance of the test date so that an agency representative may be present, if desired.

Section 2.0 of this document provides a brief process description of the sampling location. Section 3.0 presents the emissions testing strategy. Section 4.0 outlines the procedures and test methods to be used. Section 5.0 discusses the quality assurance/quality control measures to be followed during sampling and analysis. Section 6.0 discusses reporting for the test program. A copy of the FDEP air permits for these facility sources is included in Appendix A. Sample data and calibration sheets are contained in Appendix B and Appendix C contains sample calculations.

2.0 PROCESS DESCRIPTION AND SAMPLING POINT LOCATIONS

The Unit 1 combustion turbine at the Tiger Bay Cogeneration Facility is a General Electric PG7221FA (Frame 7FA) gas turbine driving a generator with a nominal electrical output rating of about 184 MW. The turbine is operated in the combined cycle mode.

The turbine is equipped with state-of-the-art multi-nozzle, quiet dry low-NO_x combustors. NO_x control is accomplished by using a premixed flame (rather than the conventional diffusion flame). The unit is equipped with a Deltak heat recovery steam generation system (HRSG) which provides high pressure steam to drive a steam turbine generator rated at approximately 84 MW electrical output. The unit also is equipped with a 100 MMBtu/hr (based on HHV) natural gas fired duct burner for supplemental heat input. The combined maximum electrical output of the steam turbine and the combustion turbine generators is approximately 258 MW.

The exhaust stack is circular with an outside diameter of 19'. Four test ports are located at 90° intervals around the stack at the 157' level. The test ports are 4" pipe with flanged covers. The sampling ports meet the criterion of EPA Method 1 for location of sampling points.

Using EPA Method 1 criteria, the maximum number of traverse points at this test location for particulate sampling is 24. EPA Method 20 requires that 48 points be used for an O_2 traverse to select the points for testing.

3.0 EMISSION TEST APPROACH

The test matrix for the emissions sampling program is given in Table 3-1. A total of 15 test runs will be conducted 3 at each condition. EPA Method 20 requires that each of the lowest 8 points of oxygen be tested in the stack for a duration of 1 minute plus the response time for each point. Therefore, the typical run time requirements for Method 20 is between 12 and 16 minutes. However, for this sampling program each test run will be at least 21 minutes in duration in order to meet the minimum run time for CEMS certification by RATA as given in PS2 of 40CFR60, Appendix B. During the maximum load tests, for both the turbine and duct burner, the test duration will be at least one hour for each parameter. Particulate matter samples will be collected for approximately two hours in order to meet the low detection limits required to demonstrate compliance with the emissions standard. A visible emissions test will be conducted simultaneously with one of the particulate matter tests during the maximum load tests both with and without the duct burner in service.

A preliminary oxygen traverse will be conducted to determine the lowest 8 points of oxygen in the exhaust stack. If stratification of the gas is determined to exist in the duct, the lowest eight points of oxygen will be traversed by Method 20 during the tests. If the gases are not stratified in terms of oxygen concentrations, then eight convenient points will be used for the Method 20 traverses for each run. The criteria that will be used to determine the existence of stratification will be a difference of greater than 0.4%V oxygen between any two traverse points. (Note that the maximum allowable error of the method is 0.5%V oxygen.)

3.1 SCHEDULE OF ACTIVITIES

The proposed schedule of activities for the test program is given below:

Week 1   Prepare emissions testing equipment and check out. Prepare and submit Compliance Test Protocol.

Week 2   On site testing.

      Day 1   Travel to site and setup equipment. Conduct NO_x converter efficiency test and preliminary measurements as time permits. Conduct preliminary O_2 traverse.

      Day 2   Conduct testing for 3 low loads for NSPS requirements for NO_x and O_2.

      Day 3   Conduct 4 tests for NO_x, O_2, CO, Particulate Matter, VE, and VOC for maximum load for the turbine and/or duct burner.

      Day 4   Conduct 2 tests for NO_x, O_2, CO, Particulate Matter, VE, and VOC for maximum load for the turbine and/or duct burner.
- Demobilize equipment.

      Day 5   Travel - Provide preliminary results to Destec.

Week 3   Finalize results and submit to Destec.

Week 4   Submit draft report to Destec.

Week 5   Submit final report to Destec.

Week 6:   Submit final report to FDEP.

Note that the actual order of the tests may be changed if required due to operational constraints. A more aggressive test schedule may also be observed if deemed appropriate by ESE and Destec.

Table 3-1. Emissions Test Matrix

Test Contidions	Turbine Load	Duct Burner Load	Test Parameter
1	Low Load	0	O_2, NO_X
2	Intermediate Load #1	0	O_2, NO_X
3	Intermediate Load #2	0	O_2, NO_X
4	Maximum	0	O_2, NO_X, CO, VOC, Particulate and VE
5	Maximum	Maximum	O_2, NO_X, CO, VOC, Particulate and VE

Source: ESE, 1994.

Note: Ambient conditions and process data will be measured during each test run in order to perform the ISO correction for NO_X.

4.0 PROCEDURES AND EPA TEST METHODS

This section includes a brief description of the test methods to be used and the sampling strategy to be followed for the testing.

4.1   METHOD 1: SAMPLE AND VELOCITY TRAVERSE

The location of the traverse points used to determine the velocity of the stack gas within the circular stack is based on the relation of the stack diameter to the upstream and downstream distances. The traverse points used for the velocity traverse will be determined from Figure 1-2 and Table 1-2 of Method 1, Appendix A, 40 CFR 60.

4.2   METHOD 2: VELOCITY AND VOLUMETRIC FLOW RATE

The average gas velocity in the stack will be determined from measurement of the velocity head with a Type "S" Pitot tube. Calibration will be performed to verify the face opening alignments, external tubing diameter, and base-to-opening plane distances. A base line coefficient value of 0.84 will be assigned to each pitot tube.

4.3   METHOD 3: ORSAT SAMPLING

Nitrogen, oxygen, and carbon dioxide stack gas concentrations will be determined with an ORSAT analyzer. Sample gas from the stack source will be collected in a leak-free Tedlar bag for the same sampling period as each test period. The Tedlar bag collected gas will be analyzed three times with the Orsat analyzer. The Tedlar bag will be evacuated, purged with air, evacuated again, and prepared for the next test run.

4.4   METHOD 4: MOISTURE CONTENT

The moisture content of a gas stream will be determined by extracting the gas sample at a known and regulated rate through a glass condenser train. The condenser train consists of four glass impingers connected in series with leak free glass U-tube

connectors. The gas sample will be extracted through the impinger train (maintained below 68°F in an ice bath) with a vacuum pump and the amount of gas sampled will be measured with a calibrated dry gas meter. The sample rate will be regulated with an orifice meter and at least twenty-one (21) standard cubic feet will be collected during the test period. The amount of moisture collected will be determined gravimetrically and the amount of gas drawn, corrected to dry, standard conditions will be determined. The meter box calibration forms are contained in Appendix B.

4.5 EPA METHOD 5 - PARTICULATE SAMPLING AND ANALYSIS

The sampling and analytical procedures used follow the procedures as outlined in EPA Method 5, in the Code of Federal Regulations, Chapter I, Title 40, Part 60, Appendix A, Method 5, revised as of July 1, 1989. The sampling equipment consists of the following:

1. Sample Probe Assembly
    a. Nozzle--Stainless steel with a sharp, tapered leading edge.
    b. Probe--Stainless steel (S.S.) sheath with a 1/2 inch diameter glass insert wrapped with nichrome wire; rheostat controlled and capable of maintaining a temperature of 248 +/-25 degrees Fahrenheit (°F).
    c. Pitot--Type "S" constructed and attached to probe according to specifications outlined in the Code of Federal Regulations, Chapter I, Title 40, Part 60, Appendix A, Method 2.
    d. Orsat Probe--Stainless steel 1/4 inch tubing attached to pitot tube in an interference-free arrangement.
    e. Thermocouple--Type "K" attached to the pitot tube such that the tip has no contact with metal and does not interfere with the pitot tube face openings.
2. Filter Holder--Glass with fitted glass filter support.

3.   Filter Heating Assembly--Controlled heating element in aluminum module attached to end of probe; capable of maintaining 248 +/-25°F.

4.   Impingers--Four impingers connected in series with glass ball/socket joint fittings and placed in an ice bath.   A Greenburg-Smith impinger tip configuration is used for the second impinger. The first, third, and fourth impingers are the modified Greenburg-Smith design with a standard tip. Final gas exit temperature is measured to within +/-2°F with a type "K" thermocouple immersed in the gas stream.

5.   Control Box--Model containing vacuum gauge, external leak-free pump, thermocouples capable of measuring temperature to within +/-2°F, dry gas meter with a minimum of 2 percent accuracy, valves and related equipment as required to maintain an isokinetic sampling rate, and to determine sample volume.

Prior to leaving the laboratory, glass fiber filters are numbered for identification, heated for 2 hours at 105° C, desiccated for 2 hours, and pre-weighed to the nearest 0.1 mg. Silica gel (indicating type, 6-16 Mesh) is also pre-weighed to 200 grams after drying for 2 hours.

Upon arrival at the sampling site, the control box is leak-checked from pump to orifice at 5 to 7 inches of water.

The sample train is prepared in the following manner: 100 mL of H_2O is added to the first and second impingers. The third impinger is left empty, and a pre-weighed quantity of silica gel is added to the fourth impinger for final moisture removal. After assembling the train with the pitobe as shown in the schematic, the system is leak-checked by plugging the inlet to the probe nozzle and pulling a vacuum of at least 15 inches of mercury "Hg. A leakage rate not in excess of 0.02 cfm is considered

acceptable. The pitot tube system is also leak-checked at 2 to 3 inches of water, and any leaks found are corrected.

The inside dimensions of each stack are measured and recorded. The number of sampling points and the location of these points on a traverse are determined by the guidelines set forth in the Code of Federal Regulations, Chapter I, Title 40, Part 60, Appendix A, Method 1. These points are then marked on the probe for easy visibility.

A preliminary traverse is conducted to determine the range of velocity head and the pressure of the stack. An approximate stack temperature is obtained during the same traverse, and an approximate moisture content is estimated based on knowledge of the emission source type and attendant characteristics and prior testing experience. From these data, the correct nozzle size and isokinetic K-factor are determined.

The probe is attached and the heater adjusted to provide a gas temperature of approximately 250°F. The filter heating system is turned on, and crushed ice placed around the impingers. After a suitable warmup period, the nozzle is placed at the first traverse point with the tip pointing directly into the gas stream. The pump is started and the sampling rate adjusted to isokinetic conditions. After the required time interval has elapsed, the probe is repositioned to the next traverse point, and isokinetic sampling re-established. This will be done for each point on the traverse until the run is completed. Readings are taken at least every 5 minutes, or when significant changes in stack conditions necessitated additional adjustments in flow rate. At the conclusion of each run, the pump is turned off and the final readings are recorded. A final leak-check of the system is performed as previously described at the highest vacuum encountered during testing, and a leak-check of the pitot system is repeated.

4.5.1 SAMPLE RECOVERY

The collection train is carefully moved to a convenient sample recovery area in order to minimize the loss of collected sample or the gain of extraneous particulate matter. The volume of condensate in the first three impingers is measured and recorded on the field data sheet. The probe, nozzle, and all sample-exposed surfaces are will rinsed with reagent grade acetone and put into a clean sample bottle marked "pre-filter". A brush is used to loosen any adhering particulate matter, and subsequent rinses are put into the "pre-filter" container. The filter is carefully removed from the fitted glass support and placed in its original container. The silica gel is removed from the fourth impinger and transferred to its original container. A sample of the acetone used in rinsing the probe is saved for a blank laboratory analysis.

4.5.2 ANALYTICAL PROCEDURES

The filter and any loose particulate matter are transferred from the sample container to a clean, tared glass weighing dish. The filter is placed in an oven at 105°C for 2 hours, desiccated for 2 hours, and then weighed. The original weight of the filter is deducted, and the weight gain recorded to the nearest 0.1 mg.

The "pre-filter" and blank solutions are transferred to clean, tared beakers, then evaporated to dryness and desiccated to a constant weight. The blank correction is made, and the weight gain recorded to the nearest 0.1 mg. The silica gel is weighed, and the weight gain recorded to the nearest 0.1 gram.

4.6   CONTINUOUS EMISSION MONITORING

Stack gas emissions of oxides of nitrogen (NO_x), carbon monoxide (CO), and volatile organic compounds (VOC) will be measured using continuous emission monitors (CEMS). Diluent oxygen concentration is also measured using CEM techniques. These tests will be performed in accordance with EPA Methods 3A for oxygen, 10 for CO, 20

for NO_x, and 25A for VOC as outlined in Title 40, Part 60, Appendix A of the Code of Federal Regulations. In addition, EPA Method 18 may be used to determine methane content for the determination of non-methane organic compounds. Copies of all on-line CEM data collected during the testing and copies of the backup strip charts will be presented in an Appendix to the report. Calibration records are also given with the data.

Flue gas sample is withdrawn from the stack at a constant rate via a stainless steel sample probe. The sample probe is equipped with an additional stainless steel line to enable probe tip calibrations. The probe is of sufficient length to allow traversing across the duct as required by EPA Method 20. Extracted sample is passed from the probe through a filter and a heated teflon sample line to the moisture removal system. The moisture removal system (gas conditioner) is designed for minimal contact between condensate and sample gas in order to prevent any reaction between the moisture and the measured pollutants. All components of the sampling and gas conditioning system are fabricated from borosilicate glass, teflon, or stainless steel. The gas conditioning system consists of a continuously downward teflon condenser coil (to prevent bubbling) and two glass knockout condenser traps. Moisture is continuously removed from the traps by an external peristaltic pump. The gas conditioning system is cooled in an ice water bath to facilitate complete moisture removal. Dry gas sample from the gas conditioner is transported to the instrument trailer via a heated 1/4-inch O.D. teflon tube to a teflon-lined diaphragm pump which delivers positive pressure sample to the instrument system. Flow control valves are used to deliver the stack gas at a regulated positive pressure to the continuous emissions monitors through a teflon and stainless steel manifold delivery network. Flow and pressure to all monitors is held constant by monitoring sample and bypass rotameters. A diagram of the CEM system used for the test program is given in Figure 4-1.

The sampling systems are leak checked by passing known calibration gas standards up through a calibration line to the end of the probe. The gas standards are then pulled back through the sampling probe at stack pressure and subsequently through the entire sampling system to the instrument system. An oxygen analyzer response of less than or equal to 0.5% V to a zero oxygen standard is considered an acceptable leak check.

Analyzer calibration error is calculated by the difference between the known calibration gas concentration and the concentration exhibited by the analyzer. Bias checks are performed by comparing calibration responses through the entire sampling system to these exhibited at the analyzer.

Acceptable system performance checks do not exceed +/-2% calibration error, +/-5% system bias check, +/-2% zero drift, and +/- 2% upscale drift.

Instrument response time is found by alternating zero nitrogen and upscale span gases through the bias check line and recording the upscale and downscale time. The response time of the CEM sampling system will be performed in accordance with EPA Method 20 to determine the length of time for the CEM's to respond to changes in the stack gas exhaust stream. Known, Protocol 1 NO_x reference gases and zero nitrogen are passed through the heated sample line, sample conditioning system and the manifold delivery network to the continuous emission monitors. Response time test results can be seen on an applicable field data worksheet and the NO_x strip chart recordings located in an Appendix to the report.

A preliminary oxygen traverse will be performed on the turbine exhaust for the purpose of selecting the eight points of lowest oxygen concentration which will be subsequently used for emissions sampling. The traverse will be performed at the lowest load to be

tested. For the preliminary oxygen traverse, the minimum number of traverse points are:

- 8 for stacks with area less than 16.1 ft^2;

- 8 + (Area of Stack (Ft^2))/2.2 , for stacks with areas between 16.1 to 107.6 ft^2; or

- 48 or 49 for stacks greater than 107.6 ft^2.

The minimum sampling time at each point is one minute plus the average system response time. Based on the results of the traverses, if all of the points are within 0.4% oxygen of each other, then 8 convenient sample points will be used for the testing.

4.7 CEM DATA ACQUISITION

The ESE data acquisition system (DAS) for the CEM analyzers consists of a DianaChart PC Acquisitor and a proprietary ESE Data Acquisition program. The data are stored on disk as well as on a printed hardcopy for each run. All data is also recorded on a strip chart recorder. The computer used is a 25-MHz 386 system with 4-MB of RAM and a math co-processor as well as a color VGA monitor. The system has 16-bit analog to digital conversion resolution (1 in 64,000) and a scan rate of approximately 1200 readings per minute. Data are averaged and reported by the DAS on a 60-second basis. The averaging time may be changed if desired. The system is capable of displaying the on line results in measured units and corrected to 15% oxygen and ISO conditions and in lb/MMBtu. Run averages are generated immediately at the end of each run.

4.8 CEM PRINCIPLES OF OPERATION

4.8.1 METHOD 3A: OXYGEN ANALYSIS

Flue gas sample is continuously analyzed for oxygen by a Servomex Model 1400A paramagnetic instrument. The Servomex 1400A analyzer uses electron paramagnetic

resonance to detect the presence of oxygen molecules. Unlike most substances, oxygen has a triplet electron ground state which leaves one electron unpaired, making it a paramagnetic molecule. This electron may have one of two quantum spin states ($m_s =$ +/- 1/2). By applying an alternating electromagnetic field of the proper frequency, the Servomex 1400A O_2 analyzer induces resonance between the two spin quantum states. In effect, the O_2 analyzer measures the electromagnetic energy absorbed by O_2 molecules at the resonant frequency.

4.8.2 METHOD 20: OXIDES OF NITROGEN ANALYSIS

A Thermo Electron Model 10AR instrument will be used to analyze NO_x. The principle of operation of this instrument is a chemiluminescent reaction in which ozone (O_3) reacts with nitric oxide (NO) to form oxygen (O_2) and nitrogen dioxide (NO_2). During this reaction, a photon with a specific ultraviolet wavelength is emitted which is detected by a photomultiplier tube. The instrument is capable of analyzing total oxides of nitrogen (NO + NO_2) by thermally converting NO_2 to NO in a separate reaction chamber prior to the photomultiplier tube, if desired. The analyzer will be operated in the NO_x mode during sampling.

A convertor efficiency test will be performed on the Thermoelectron Model 10s during the compliance test series. A leak-free Tedlar bag will be partially filled with a Protocol 1 NO_x reference gas. The Tedlar bag is then filled to capacity with a Certified Oxygen reference gas standard. The contents are well mixed and immediately connected to the sample inlet of the analyzer. The Tedlar bag is analyzed by the analyzer in the "NO_x" mode for at least thirty minutes. A decrease in response in the NO_x mode of more than 2% indicates that corrective action is required.

4.8.3   METHOD 10: CARBON MONOXIDE ANALYSIS

A TECO 48 Gas Filter Correlation Non-Dispersive Infrared (GFC/NDIR) analyzer will be used for continuous CO analysis. The principle of operation of this analyzer is similar to traditional NDIR analyzers in that it relies on selective absorption; whereby, particular band widths of infrared energy are absorbed by a species based on its molecular orbital structure. Gas filter correlation NDIR differs from NDIR in the detection mechanism and because the GFC/NDIR does not require a reference cell. Infrared radiation passes through a rotating filter, through the sample cell and to the detector. The chopper wheel of the GFC/NDIR is a rotating disk separated into two chambers where one half is filled with nitrogen and the other half is filled with pure CO. These partitions act as alternating gas filters for the incident IR radiation from the IR source. The CO gas filter side acts to produce a signal which cannot be further attenuated by CO in the sample cell and is used as a reference signal. The nitrogen filter allows all incident radiation to pass. Carbon monoxide in the sample cell will, therefore, attenuate the signal proportionally to concentration. This is considered the measure cycle. Any other gases which absorb infrared radiation are absorbed equally during both the measure and reference cycles, providing a real-time reference and minimal interferences. The detector for this analyzer is a lead-selenium photodetector.

4.8.4   METHOD 25A: TOTAL HYDROCARBONS

EPA Method 25A will be used to measure VOC expressed as total hydrocarbons. The results will be reported on a parts per million by volume as carbon basis (ppmC). Methane in air will be the calibration standard. A gas sample is extracted from the source through a heated sample line and a glass fiber filter, directly into a hydrocarbon analyzer. The analyzer uses the flame ionization principle (FID) to detect hydrocarbons on a continuous basis.

4.8.5 METHOD 18: NON-METHANE VOLATILE ORGANIC COMPOUNDS

EPA Method 18 will only be used if it is determined that the VOC limits are not met using the total hydrocarbons measurement (EPA Method 25A). Because the unit burns natural gas, the potential exists for methane to be present in the gas stream. Since methane is a non-photoreactive hydrocarbon, it is not considered a VOC. If the results of the Method 25A total hydrocarbon analysis are found to be higher than the emission limit, then a sample will be collected in an evacuated canister for analysis of methane by GC/FID using EPA Method 18. Total non-methane volatile organic compound concentration would then be expressed on a carbon basis and will be calculated as the difference between the Method 25A and the Method 18 results.

4.9 PERFORMANCE SPECIFICATION TEST PROCEDURES FOR CEMS CERTIFICATION

Performance specifications for NO_x and oxygen (O_2) CEMS are contained in 40 CFR Part 60, Appendix B, Specifications 2 and 3 (PS2 and PS3). The performance specifications require an initial performance evaluation in which two criteria are evaluated: 1) calibration drift (CD), and 2) relative accuracy (RA). The performance specifications require that the magnitude of the calibration drift be determined once every 24 hours for 7 consecutive days. To determine relative accuracy, at least nine reference method test runs are collected simultaneously with CEM data for each analyzer. The performance specifications require an initial 168 hour conditioning period followed by a 7 - day calibration drift test.

4.9.1 CALIBRATION DRIFT EVALUATION

During the calibration drift evaluation, the facility must be operating at more than 50 percent of normal load. Since operating restrictions and load demand requirements do not allow operating all three of the units simultaneously at loads in excess of 50%, the

drift tests were conducted separately for each of the units in order to accommodate this requirement. Destec will conduct the calibration drift evaluation.

The calibration drift is measured at two points: zero and a high level value. For the Tiger Bay Cogeneration Facility CEMs, the high-level value must be between 1.5 times the pollution concentration corresponding to the emission standard and the span value.

4.9.2 RELATIVE ACCURACY EVALUATION

The performance specifications require that the relative accuracy evaluation be conducted while the facility is operating at more than 50% of normal load. Destec will operate the unit at greater than 50% load while firing natural gas during the RATA evaluation period. The NO_x, and O_2 analyzers will be certified by RATA against concentrations measured according to EPA Reference Method 20 and EPA Reference Method 3A. Performance specifications require a minimum of nine sets of reference method tests. More than nine tests may be conducted and up to three sets may be rejected, provided that at least 9 runs are used in the analysis. All data including the rejected data must be reported. Each set is at least 21 minutes in duration. Relative Accuracy comparisons are made based on the as measured parameters for O_2 and in the units of the standard (lb/MMBtu) for NO_x. NO_x emission rates in lb/MMBtu are calculated using $F_d=8710$, the raw NO_x concentration, and the raw O_2 concentration as described in EPA Method 19.

4.9.3 CORRELATION OF REFERENCE METHODS AND CEM DATA

The reference method and the CEM data are correlated over the reference method sampling period. The concentrations are adjusted to the same basis for moisture, temperature and diluent concentration. The CEM data are averaged over the sampling period and then compared to the reference method result. All measurements for both the reference method system and the CEMS were conducted on a dry basis.

4.9.4 CALCULATIONS

For determining relative accuracy, the differences are calculated between the reference method and CEMs value for all gas analysis, and between the reference method and the calculated flow protocol for total flow. Then, the mean difference, standard deviation of the differences, and confidence coefficient are used to calculate the relative accuracy. The equations used are contained in Section 8, of 40 CFR Part 60, Appendix B, Performance Specification 2. Sample calculations using test data from this program are included in Appendix B of this document.

4.9.5 ACCEPTANCE CRITERIA

The acceptance criteria for the respective analyzer systems are summarized in the Table 4-1. Relative Accuracy comparisons may be expressed as a percentage of the average reference method result or of the emissions standard. The calibration drift results are compared to the drift criteria each day. In the event that a daily drift does not meet the criteria, a new 7-day period can be started from the next day the drift is within the acceptance criteria.

Table 4-1. Analyzer Performance Acceptance Criteria		
Analyzer	Calibration Drift	Relative Accuracy
NO_x	< 2.5% of span	< 20% of RM result[a]
O_2	< 0.5% O_2	< 20% of RM result[b]

[a] Or 10% of the applicable emissions standard.
[b] Or 1.0 percent oxygen by volume relative to the average reference method result.
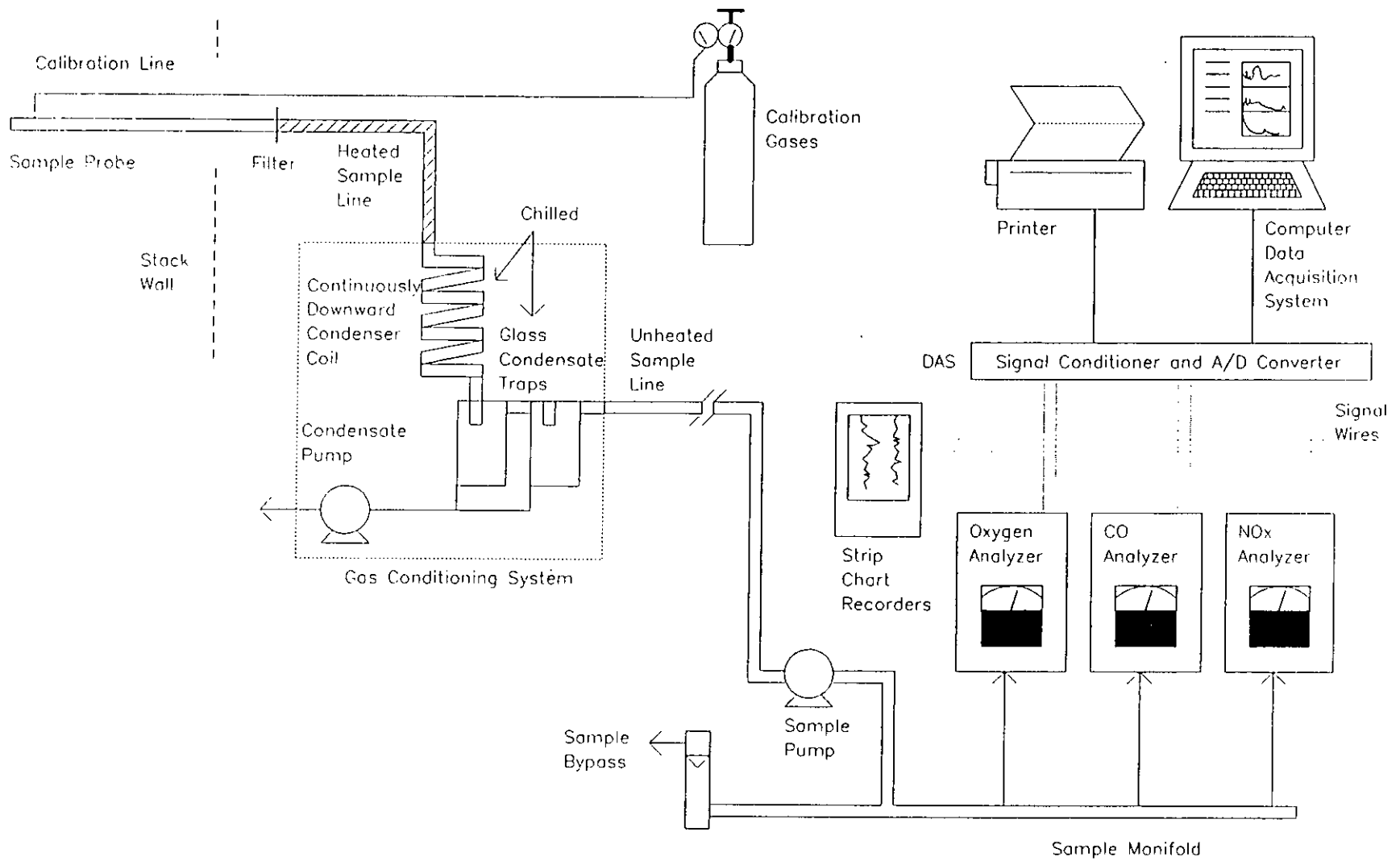
Figure 4-1. Schematic Diagram of ESE·CEM System.

5.0 QUALITY ASSURANCE/QUALITY CONTROL

Strict Quality Assurance/Quality Control (QA/QC) measures will be observed for all sampling and analysis performed for the Tiger Bay Cogeneration Facility test program. The QA/QC program is designed to provide the highest quality data in terms of the accuracy and precision of the measurements as well as the representativeness and comparability of the results.

5.1 MANUAL METHODS QA/QC

The ESE QA/QC program for this test series includes all of the QA/QC guidelines given in EPA Methods 1-4, 5 and 17 (40 CFR Pt 60, Appendix A) in addition to internal QA/QC standards. Primary components of the QA/QC program for the manual sampling techniques are listed below:

- Equipment Calibrations - including meter boxes, thermocouples, pitot tubes and analytical balance.

- Equipment Leak Checks - including pre- and post-test sample train leak checks, meter and pump leak checks, pitot leak checks and ORSAT system leak checks.

- Careful monitoring and documentation of sample train critical parameters including temperatures and meter pressure.

- Preliminary measurements to aid in calculating the sampling K-factor used to determine isokinetic sampling rate.

- Maintaining an isokinetic sampling rate so that the velocity through the sampling nozzle matches the surrounding flue gas stream velocity to within +/- 10%.

All sampling train leak rates will be less than the maximum acceptable leak rate of 0.02 cubic feet per minute. Sample train leak checks are performed at a vacuum of at least 5" Hg greater than the highest observed vacuum observed during sampling. All samples are desiccated and replicate analyses are performed until agreement of 0.5 mg between

weighings which were eight hours apart. Blanks are analyzed for the acetone used in sample recovery as well as for the filters used.

5.2   INSTRUMENTAL SAMPLING AND ANALYSIS

5.2.1   CALIBRATIONS AND DRIFT ASSESSMENTS

At the beginning of each test day, the EPA Reference Method 20, 3a, 10, and 25A test equipment will be calibrated, and adjusted as required, on a two-point basis. Subsequently, additional calibration standards will be introduced to the analyzers to check the linearity of the instrument response. If the linearity of the instrument is within +/-2% of full scale of the calibration standard value, the calibration is accepted. Otherwise, corrective maintenance will be performed, and the instrument will be calibrated. Final calibrations will be performed at the conclusion of each test day to determine calibration drift.

5.2.2   NO$_2$ CONVERTER EFFICIENCY

Prior to arrival on-site, an NO$_2$ to NO converter efficiency test will be performed as . prescribed in EPA Method 20. The procedure used for testing the converter efficiency is given below:

- Fill a leak-free Tedlar bag approximately half-full with an NO in N$_2$ blend.
- Fill the remainder of the bag with 0.1 grade air.
- Immediately attach the NO/Air mixture to the inlet of the NO$_x$ monitor being used.
- Allow the monitor to sample the gas in the bag for 30 minutes.

As the O$_2$ and NO in the bag are exposed to each other, a reaction occurs which changes the NO to NO$_2$. An attenuation in response over time of greater than five percent absolute indicates that the converter efficiency is unacceptable.

5.2.3 INSTRUMENT RESPONSE TIME

Instrument system response time will be determined by inserting the reference method sampling probe into the stack from ambient and noting the time required for NO_x monitor to achieve a change of 95% of the final stack concentration. The response time data sheet will be included in the final report.

5.2.4 LEAK CHECKS

Since all calibrations are performed through the entire sampling system, leak-checks are incorporated in each calibration. The criterion used for this test will be an oxygen response of less than 0.5% O_2 to an oxygen-free zero gas. Nitrogen will be passed through the entire sampling system at ambient pressure to check for an oxygen response of zero in all cases.

6.0 REPORTING

Test results will be reported to FDEP expressed in terms of as measured concentrations, and pollutant emissions limitations as expressed in the air permit. At a minimum the report for the test program will include the following sections:

1.0 Introduction

2.0 Process Description and Sampling Point Locations

3.0 Summary and Discussion of Results

4.0 Sampling and Analytical Procedures

5.0 Quality Assurance/Quality Control

Additionally, copies of all raw data, calculations, certifications, calibrations, analytical data, process data collected, and a list of project participants will be included in a set of appendices to the report.

The report will be submitted to FDER by Destec no later than 45 days of completion of the testing.

Separate reports will be issued for the CEMS RATA certification and for the compliance testing.

ANTICIPATED LIST OF PROJECT PARTICIPANTS

ESE

Clifton R. Bittle	Project Director
Bill Mayhew	Project Manager/Crew Chief
Norman Czarniak	Environmental Technician
M. Norman Czarniak	Environmental Technician

DESTEC

Scott Kicker	Coordinator

FDER

To be named	Test Observer

APPENDIX A

AIR PERMIT

Final Determination

Central Florida Power, Limited Partnership
Ft. Meade, Polk County, Florida

258 MW Cogeneration Facility

Permit Number: AC53-214903
                 PSD-FL-190

Department of Environmental Regulation
Division of Air Resources Management
Bureau of Air Regulation

May 6, 1993

The Technical Evaluation and Preliminary Determination for the permit to construct a 258 cogeneration facility at Central Florida Power, Limited Partnership (CFPLP), in Ft. Meade, Polk County, Florida, was distributed on January 15, 1993. The Notice of Intent to Issue was published in The Polk County Democrat on February 4, 1993. Copies of the evaluation were available for public inspection at the Department's offices in Tampa and Tallahassee.

CFPLP's application for a permit to construct a 258 MW cogeneration facility has been reviewed by the Bureau of Air Regulation in Tallahassee. No adverse comments were submitted by the U.S. Environmental Protection Agency (EPA) in their letter dated February 16, 1993, or by the U.S. Department of the Interior (Fish and Wildlife Services) in their letter of February 5, 1993.

Comments regarding the Technical Evaluation and Preliminary Determination (Synopsis of Application) and Permit Specific Conditions were submitted by Kennard F. Kosky, P.E., President of KBN Engineering and Applied Sciences, Inc. The Bureau has considered Mr. Kosky's comments and agreed to the changes proposed in the wording and adjustment of numerical limits to reflect manufacturer's specifications since these changes will not affect the potential emissions considered during the evaluation of this project. The amendments to the Specific Conditions of the permit are as follows:

RESPONSE TO COMMENTS NOS. 1, 2, 3, 4, AND 5

These changes will be incorporated in Table 1.

RESPONSE TO COMMENTS NOS. 5 AND 6

The table on page 9 of the BACT determination and Table 1 of the permit (Specific Condition No. 1) will be amended to reflect these comments.

BACT DETERMINATION BY DER (PAGE 8)

This paragraph will be added to the NO_x control section: For this turbine, an even lower NO_x emission level than 15 (gas)/42 (oil) ppmvd, corrected to 15% O_2, may become a condition of this permit pursuant to F.A.C. Rule 17-4.080, Modification of Permit Conditions.

RESPONSE TO ITEM NO. 2 ON KBN'S LETTER OF JANUARY 30, 1993

Information given to DER and to the U.S. Department of Interior (Fish and Wildlife Services) indicates that General Electric's goal is to attempt a NO_x level of 9 ppmvd when firing natural gas.

IN RESPONSE TO THE U.S. DEPARTMENT OF INTERIOR, SPECIFIC CONDITION NO. 15 WILL BE CHANGED AS FOLLOWS:

FROM: The permittee shall leave sufficient space in the heat recovery steam generator suitable for future installation of SCR equipment should the facility be unable to meet the NO_x standards, if required.

TO: The permittee shall comply with the following by 12/31/97:

a) For this turbine, if the 15 (gas)/42 (oil) ppmv emission rates cannot be met by 12/31/97, SCR or other control technology will be installed. Hence, the permittee shall install a duct module suitable for future installation of SCR equipment.

IN RESPONSE TO THE MARCH 11, 1993, LETTER FROM KENNARD F. KOSKY, KBN

The Department has determined the following:

Mandating SCR: The Department is giving the permittee the flexibility to incorporate any design feature to meet the 15 (gas) ppmvd at 15% O_2 NO_x emission limit. SCR or other control technology shall be installed if the 15 (gas) ppmvd cannot be met by 12/31/97.

Lowering the permit/BACT limit for NO_x: The Department may revise the permitted emission level for NO_x. For this turbine, an even lower NO_x emission level than 15 (gas)/42 (oil) ppmvd, corrected to 15% O_2, may become a condition of this permit, pursuant to F.A.C. Rule 17-4.080, Modification of Permit Conditions.

SPECIFIC CONDITION NO. 14 WILL BE MODIFIED AS FOLLOWS. THE PARAGRAPH IN BOLD WAS INADVERTENTLY OMITTED IN THE DRAFT PERMIT

Specific Condition No. 14: Test results will be the average of 3 valid runs. The Southwest District office will be notified at least 30 days in writing in advance of the compliance test(s). The sources, combustion turbine and duct burner, shall operate between 95% to 100% of the maximum capacity for the ambient conditions experienced during compliance test(s). The turbine manufacturer's capacity vs temperature (ambient) curve shall be included with the compliance test results. Compliance test results shall be submitted to the Southwest District office no later than 45 days after completion.

The final action of the Department will be to issue construction permit AC53-214903 (PSD-FL-190) with the changes noted above.
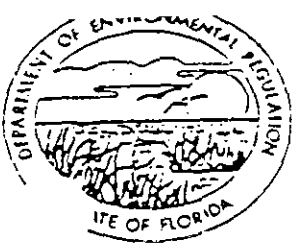
Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Virginia B. Wetherell, Secretary

PERMITTEE:
Central Florida Power, L.P.
2500 City West Blvd., Ste. 150
Houston, Texas 77042

Permit Number: AC53-214903
PSD-FL-190
Expiration Date: January 1, 1996
County: Polk
Latitude/Longitude: 27°44'46.7"N
81°51'0.3"W
Project: A 258 MW Cogeneration
Facility

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-210, 212, 275, 296, 297 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

Central Florida Power, Limited Partnership, proposes to operate a 258 MW cogeneration facility consisting of one combustion turbine generator, one steam turbine generator, one duct burner-fired heat recovery steam generator and ancillary equipment. This facility is located near Ft. Meade, Polk County, Florida. The UTM coordinates are Zone 17, 416.22 km East and 3069.22 km North.

The sources shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:

1. Central Florida Power, Limited Partnership's (CFPLP) application received on June 15, 1992.
2. Department's letters dated July 14 and October 9, 1992.
3. CFPLP's letters received on August 26, October 9, and October 23, 1992.

GENERAL CONDITIONS:

1.   The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2.   This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3.   As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4.   This permit conveys no title to land or water, does not constitute State recognition or acknowledgement of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5.   This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6.   The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

GENERAL CONDITIONS:

7.   The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

   a. Have access to and copy any records that must be kept under the conditions of the permit;

   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and

   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8.   If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

   a. a description of and cause of non-compliance; and

   b. the period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

     The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9.   In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes.   Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

GENERAL CONDITIONS:

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.120 and 17-30.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

(x) Determination of Best Available Control Technology (BACT)
(x) Determination of Prevention of Significant Deterioration (PSD)
(x) Compliance with New Source Performance Standards (NSPS)

14. The permittee shall comply with the following:

a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c. Records of monitoring information shall include:

- the date, exact place, and time of sampling or measurements;

PERMITTEE:
Central Florida Power, L.P.

Permit Number: AC53-214903
PSD-FL-190
Expiration Date: January 1, 1996

GENERAL CONDITIONS:

- the person responsible for performing the sampling or measurements;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- the results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SPECIFIC CONDITIONS:

Emission Limits

1. The maximum allowable emissions from this source shall not exceed the emission rates listed in Table 1.

2. Visible emissions for full load operation shall not exceed 10% opacity when firing natural gas and 20% opacity when firing distillate fuel oil.

Operating Rates

3. This source is allowed to operate continuously (8,760 hours per year).

4. This source is allowed to use natural gas as the primary fuel for 8,760 hours per year and low sulfur distillate fuel oil (0.05% S) as the secondary fuel up to 3,742,327 gallons per calendar year.

5. The permitted materials and utilization rates for the combined cycle gas turbine system shall be as stated in the application. The operating parameters include, but are not limited to:

184 MW Combustion Turbine

a) The maximum heat input of 1,849.9 MMBtu/hr (LHV) at 27°F and at base load for distillate fuel oil.

b) The maximum heat input of 1,614.8 MMBtu/hr (LHV) at 27°F and at base load for natural gas.

SPECIFIC CONDITIONS:

Duct Burner

c) The maximum heat input of 100 MMBtu/hr (HHV) of natural gas.

6. Any change in the method of operation, equipment or operating hours pursuant to Rule 17-212.200, F.A.C., Definitions-Modifications, shall be submitted to DER's Bureau of Air Regulation and Southwest District offices.

7. Any other operating parameters established during compliance testing and/or inspection that will ensure the proper operation of this facility shall be included in the operating permit.

Compliance Determination

8. Compliance with the NO_x, SO_2, CO, PM, PM_{10}, and VOC standards shall be determined (while operating at 95-100% of the permitted maximum heat rate input corresponding to the particular ambient conditions) within 180 days of initial operation of the maximum capability of the unit and annually thereafter, by the following reference methods as described in 40 CFR 60, Appendix A (July, 1992 version) and adopted by reference in F.A.C. Rule 17-297.

- Method 1   Sample and Velocity Traverses for Stationary Sources
- Method 2   Determination of Stack Gas Velocity and Volumetric Flow Rate
- Method 3   Gas Analysis
- Method 5   Determination of Particulate Emissions from Stationary Sources
  or
  Method 17   Determination of Particulate Emissions from Stationary Sources
- Method 18   Measurement of Gaseous Organic Compound Emissions by Gas Chromatography
- Method 9   Visual Determination of the Opacity of Emissions from Stationary Sources
- Method 8   Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources
- Method 10   Determination of Carbon Monoxide Emission from Stationary Sources
- Method 20   Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines
- Method 25A Determination of Total Gaseous Organic Concentrations Using a Flame Ionization Analyzer

SPECIFIC CONDITIONS:

- Method 201A Determination of PM_{10} Emissions from Stationary
     and   Sources
  Method 202 Determination of Condensible Particulate Emissions
              from Stationary Sources

     Other DER approved methods may be used for compliance testing
after prior Departmental approval.

9.   Method 5 or Method 17 or Method 201A and Method 202 must be
performed to determine the initial compliance status of particulate
matter emissions of the unit. Thereafter, the opacity emissions
test, Method 9, may be used unless the applicable opacity is
exceeded. Also, the ambient particulate matter entering the gas
turbine can be subtracted from the total particulate matter
emissions if that quantity can be measured at the inlet of the gas
turbine.

10. Compliance with the SO_2 and sulfuric acid mist emission limit
can also be determined by calculations based on fuel analysis using
ASTM D4294 for the sulfur content of liquid fuels and ASTM D3246-81
for sulfur content of gaseous fuel.

11. Trace elements of Beryllium (Be) shall be tested during initial
compliance test using EMTIC Interim Test Method. As an alternative,
Method 104 may be used; or Be may be determined from fuel sample
analysis using either Method 7090 or 7091, and sample extraction
using Method 3040 as described in the EPA solid waste regulations SW
846.

12. Mercury (Hg) shall be tested during initial compliance test
using EPA Method 101 (40 CFR 61, Appendix B) or fuel sampling
analysis using methods acceptable to the Department.

13. During performance tests, to determine compliance with the
NO_x standard, measured NO_x emissions at 15 percent oxygen will be
adjusted to ISO ambient atmospheric conditions by the following
correction factor:

$$NO_x = (NO_{x\ obs}) \left(\frac{P_{ref}}{P_{obs}}\right)^{0.5} e^{19\ (H_{obs} - 0.00633)} \left(\frac{288°K}{T_{AMB}}\right)^{1.53}$$

where:

SPECIFIC CONDITIONS:

NO_x = Emissions of NO_x at 15 percent oxygen and ISO standard ambient conditions.

$NO_{x\ obs}$ = Measured NO_x emission at 15 percent oxygen, ppmv.

P_{ref} = Reference combustor inlet absolute pressure at 101.3 kilopascals (1 atmosphere) ambient pressure.

P_{obs} = Measured combustor inlet absolute pressure at test ambient pressure.

H_{obs} = Specific humidity of ambient air at test.

e = Transcendental constant (2.718).

T_{AMB} = Temperature of ambient air at test.

14.   Test results will be the average of 3 valid runs. The Southwest District office will be notified at least 30 days in writing in advance of the compliance test(s). The sources, combustion turbine and duct burner, shall operate between 95% and 100% of maximum capacity for the ambient conditions experienced during compliance test(s). The turbine manufacturer's capacity vs temperature (ambient) curve shall be included with the compliance test results. Compliance test results shall be submitted to the Southwest District office no later than 45 days after completion.

15.   The permittee shall comply with the following by 12/31/97:

a)   For this turbine, if the 15 (gas)/42 (oil) ppmvd, corrected to 15% O_2 emission rates cannot be met by 12/31/97, SCR or other control technology will be installed. Hence, the permittee shall install a duct module suitable for future installation of SCR equipment.

16.   The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from this source. The continuous emission monitor must comply with 40 CFR 60, Appendix B, Performance Specification 2 (July 1, 1992).

17.   A continuous monitoring system shall be installed to monitor and record the fuel consumption on the CT and duct burner. While water/steam injection is being utilized for NO_x control, the water/steam to fuel ratio at which compliance is achieved shall be incorporated into the permit and shall be continuously monitored. The system shall meet the requirements of 40 CFR Part 60, Subpart GG.

SPECIFIC CONDITIONS:

18. Sulfur and nitrogen content and lower heating value of the fuel being fired in the combustion turbines shall be determined as specified in 40 CFR 60.334(b). Any request for a future custom monitoring schedule shall be made in writing and directed to the Southwest District office. Any custom schedule approved by DER pursuant to 40 CFR 60.334(b) will be recognized as enforceable provisions of the permit, provided that the holder of this permit demonstrates that the provisions of the schedule will be adequate to assure continuous compliance. The records of distillate fuel oil usage shall be kept by the company for a two-year period for regulatory agency inspection purposes. For sulfur dioxide, periods of excess emissions shall be reported if the fuel being fired in the gas turbine exceeds 0.05 percent sulfur by weight.

Rule Requirements

19. This source shall comply with all applicable provisions of Chapter 403, Florida Statutes, Chapters 17-210, 212, 275, 296, 297 and 17-4, Florida Administrative Code and 40 CFR 60 (July, 1992 version).

20. The sources shall comply with all requirements of 40 CFR 60, Subpart GG and Subpart Dc, and F.A.C. Rule 17-296.800,(2)(a), Standards of Performance for Stationary Gas Turbines and Standards of Performance for Industrial, Commercial, and Institutional Steam Generating Units.

21. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements and regulations (F.A.C. Rule 17-210.300(1)).

22. This source shall be in compliance with all applicable provisions of F.A.C. Rules 17-210.650: Circumvention; 17-210.700: Excess Emissions; 17-296.800: Standards of Performance for New Stationary Sources (NSPS); 17-297: Stationary Sources-Emissions Monitoring; and, 17-4.130: Plant Operation-Problems.

23. If construction does not commence within 18 months of issuance of this permit, then the permittee shall obtain from the Department a review and, if necessary, a modification of the control technology and allowable emissions for the unit(s) on which construction has not commenced (40 CFR 52.21(r)(2)).

24. Quarterly excess emission reports, in accordance with the July 1, 1992 version of 40 CFR 60.7 and 60.334 shall be submitted to the Department's Southwest District office.

SPECIFIC CONDITIONS:

25. Fugitive dust emissions, during the construction period, shall
be minimized by covering or watering dust generation areas.

26. Pursuant to F.A.C. Rule 17-210.300(2), Air Operating Permits,
the permittee is required to submit annual reports on the actual
operating rates and emissions from this facility. These reports
shall include, but are not limited to the following: sulfur content
and the lower heating value of the fuel being fired, fuel usage,
hours of operation, air emissions limits, etc. Annual reports shall
be sent to the Department's Southwest District office by March 1 of
each calendar year.

27. The permittee, for good cause, may request that this
construction permit be extended. Such a request shall be submitted
to the Bureau of Air Regulation prior to 60 days before the
expiration of the permit (F.A.C. Rule 17-4.090).

28. An application for an operation permit must be submitted to the
Southwest District office at least 90 days prior to the expiration
date of this construction permit. To properly apply for an
operation permit, the applicant shall submit the appropriate
application form, fee, certification that construction was completed
noting any deviations from the conditions in the construction
permit, and compliance test reports as required by this permit
(F.A.C. Rules 17-4.055 and 17-4.220).

Issued this ___17th___ day
of ___May___, 1993

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

Virginia B. Wetherell
Secretary

Table 1 - Allowable Emission Rates

Pollutant	Fuel[A]	Allowable Emission[C] Standard/Limitation	Basis
NO_x (CT)	Gas	15 ppmvd @ 15% O_2 (97.2 lbs/hr; 425.7 TPY)[B]	BACT
	Gas	25 ppmvd @ 15% O_2 (161.9 lbs/hr; 709.1 TPY)	BACT
	Oil	42 ppmvd @ 15% O_2 (326 lbs/hr; 48.9 TPY)	BACT
NO_x (DB)	Gas	0.1 lbs/MMBtu (10 lbs/hr, 43.8 TPY)	BACT
CO (CT)	Gas	15 ppmvd (48.8 lbs/hr; 213.7 TPY)[D]	BACT
	Oil	30 ppmvd (98.4 lbs/hr; 14.8 TPY)	BACT
CO (DB)	Gas	10 lbs/hr; 43.8 TPY	BACT
VOC (CT)	Gas	2.8 lbs/hr; 12.3 TPY	BACT
	Oil	7.5 lbs/hr; 1.1 TPY	BACT
VOC (DB)	Gas	2.9 lbs/hr; 12.7 TPY	BACT
PM_{10} (CT)	Gas	9 lbs/hr; 39.4 TPY	BACT
	Oil	17 lbs/hr; 2.6 TPY	BACT
PM_{10} (DB)	Gas	0.0100 lbs/MMBtu	BACT
SO_2 (CT)	Gas	4.86 lbs/hr; 21.3 TPY	Appl.
	Oil	99.7 lbs/hr; 15.0 TPY	Appl.
SO_2 (DB)	Gas	0.3 lbs/hr; 1.32 TPY	Appl.
H_2SO_4 (CT)	Gas	5.95×10^{-1} lbs/hr; 2.6 TPY	Appl.
	Oil	1.22 lbs/hr; 0.183 TPY	Appl.
H_2SO_4 (DB)	Gas	3.7×10^{-2} lbs/hr; 1.61×10^{-1} TPY	Appl.
Opacity	Gas	10% opacity[D]	BACT
	Oil	20% opacity[D]	BACT
Hg	Oil	3.0×10^{-6} lbs/MMBtu (5.55×10^{-3} lbs/hr; 8.32×10^{-4} TPY)	Appl.
As	Oil	4.2×10^{-6} lbs/MMBtu (7.77×10^{-3} lbs/hr; 1.17×10^{-3} TPY)	BACT
Be	Oil	2.5×10^{-6} lbs/MMBtu (4.62×10^{-3} lbs/hr; 6.94×10^{-4} TPY)	BACT
Pb	Oil	8.9×10^{-6} lbs/MMBtu (1.65×10^{-2} lbs/hr; 2.47×10^{-3} TPY)	Appl.

A) Fuel: Natural Gas: Emissions are based on 8760 hours per year operating time.
Fuel: Distillate Fuel Oil (0.05% S): Emissions are based on fuel usage equivalent to 300 hours per year at maximum capacity (i.e., 3,742,327 gallons per year).

B) The NO_x maximum limit will be lowered to 97.2 (lbs/hr) equivalent to 15 ppmvd @ 15% O_2 not later than 12/31/97 using appropriate combustion technology improvements or SCR.

C) Emission rates are based on 27°F at base load.

D) At full load conditions.

Best Available Control Technology (BACT) Determination
Central Florida Power, L.P.
Polk County
PSD-FL-190

The applicant proposes to construct a cogeneration facility near Ft. Meade, Polk County. This generator system will consist of a 184 MW General Electric PG7221FA combustion turbine generator (CT), equipped with a duct burner-fired heat recovery steam generator (HRSG), which will be used to power a nominal 74 MW steam turbine generator (ST).

The applicant has requested to burn natural gas for 8760 hours per year and distillate fuel oil, with a 0.05 percent sulfur content for a maximum 3,742,327 gallons per year. The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the facility at base load, 27°F and type of fuel fired to be as follows:

Pollutant	Emissions (TPY) Gas		Oil	Total	PSD Significant Emission Rate (TPY)
	PG7221FA (8460 hrs)	Duct Burner (8760 hrs)	PG7221FA (300 hrs)		
NO_x	684.7	43.8	48.9	777.4	40
SO_2	20.5	1.3	15	36.8	40
PM/PM_{10}	38.1	4.4	2.6	45.1	25/15
CO	206.5	43.8	14.8	265.1	100
VOC	11.80	12.7	1.1	25.6	40
H_2SO_4	2.5	0.16	1.9	4.5	7
Be	nil	nil	6.94×10^{-4}	6.94×10^{-4}	0.0004
Hg	nil	nil	8.32×10^{-4}	8.32×10^{-4}	0.1
Pb	nil	nil	2.47×10^{-4}	2.47×10^{-4}	0.6
As	nil	nil	1.17×10^{-3}	1.17×10^{-3}	0

Florida Administrative Code (F.A.C.) Rule 17-212.400(2)(f)(3) requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table.

Date of Receipt of a BACT Application

June 15, 1992

BACT Determination Requested by the Applicant

Pollutant	Proposed Limits
NO_x	25 ppmvd @ 15% O_2 (natural gas burning)
	42 ppmvd @ 15% O_2 (for oil firing)
	Control Technology: Dry Low-NO_x Burners when
	firing natural gas and steam/water injection
	when firing distillate oil
SO_2	0.05% sulfur by weight (fuel oil firing)
CO, VOC	Combustion Control
PM/PM_{10}	Combustion Control

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-212, this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that in making the BACT determination the Department shall give consideration to:

(a) Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

(b) All scientific, engineering, and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determinations of any other state.

(d) The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine for the emission source in question the most stringent control available for a similar or identical source or source category. If it is shown that this level of control is technically or economically infeasible for the source in question, than the

next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

The air pollutant emissions from combined cycle power plants can be grouped into categories based upon what control equipment and techniques are available to control emissions from these facilities. Using this approach, the emissions can be classified as follows:

o   Combustion Products (e.g., particulates). Controlled generally by good combustion of clean fuels.

o   Products of Incomplete Combustion (e.g., CO). Control is largely achieved by proper combustion techniques.

o   Acid Gases (e.g., NO_x). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., particulates, sulfur dioxide, fluorides, sulfuric acid mist, etc,), if a reduction in "nonregulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

BACT POLLUTANT ANALYSIS

COMBUSTION PRODUCTS

Particulate Matter (PM/PM_{10})

The design of this system ensures that particulate emissions will be minimized by combustion control and the use of clean fuels. The particulate emissions from the combustion turbine when burning natural gas and fuel oil will not exceed 9 lbs/hr and 17 lbs/hr, respectively. The Department accepts the applicant's proposed control for particulate matter and heavy metals.

Lead, Mercury, Beryllium, Arsenic (Pb, Hg, Be, As)

The Department agrees with the applicant's rationale that there are
no feasible methods to control lead, mercury, arsenic, and
beryllium; except by limiting the inherent quality of the fuel.

Although the emissions of these toxic pollutants could be
controlled by particulate control devices, such as a baghouse or
scrubber, the amount of emission reductions would not warrant the
added expense. As this is the case, the Department does not
believe that the BACT determination for PM would be affected by the
emissions of these pollutants.

PRODUCTS OF INCOMPLETE COMBUSTION

Carbon Monoxide (CO)

The emissions of carbon monoxide exceed the PSD significant
emission rate of 100 TPY. The applicant has indicated that the
carbon monoxide emissions from the proposed combined cycle turbine
is on exhaust concentrations of 15 ppmv for natural gas firing and
30 ppmv for fuel oil firing.

The majority of BACT emissions limitations have been based on
combustion controls for carbon monoxide and volatile organic
compounds minimization, additional control is achievable through
the use of catalytic oxidation. Catalytic oxidation is a
postcombustion control that has been employed in CO nonattainment
areas where regulations have required CO emission levels to be less
than those associated with wet injection. These installations have
been required to use LAER technology and typically have CO limits
in the 10-ppm range (corrected to dry conditions).

In an oxidation catalyst control system, CO emissions are reduced
by allowing unburned CO to react with oxygen at the surface of a
precious metal catalyst such as platinum. Combustion of CO starts
at about 300°F, with efficiencies above 90 percent occurring at
temperatures above 600°F. Catalytic oxidation occurs at
temperatures 50 percent lower than that of thermal oxidation, which
reduces the amount of thermal energy required. For CT/HRSG
combinations, the oxidation catalyst can be located directly after
the CT or in the HRSG. Catalyst size depends upon the exhaust
flow, temperature, and desired efficiency.

Due to the oxidation of sulfur compounds and excessive formation of
H_2SO_4 mist emissions, oxidation catalyst are not considered to be
technically feasible for gas turbines fired with fuel oil.

Catalytic oxidation has not been demonstrated on a continuous basis when using fuel oil.

Use of oxidation catalyst technology would be technically feasible for this natural gas-fired unit; however, the cost of $10,000 per ton for the PG7221FA of CO removed will have an adverse economic impact on this project.

The Department is in agreement with the applicant's proposal of combustor design and good operating practices as BACT for CO for this cogeneration project.

ACID GASES

Nitrogen Oxides (NO_x)

The emissions of nitrogen oxides represent a significant proportion of the total emissions generated by this project, and need to be controlled if deemed appropriate. As such, the applicant presented an extensive analysis of the different available technologies for NO_x control.

The applicant has stated that BACT for nitrogen oxides will be met by using water/steam injection (when firing distillate fuel oil) and advanced combustor design to limit emissions to 25 ppmvd (corrected to 15% O_2) when burning natural gas and 42 ppmvd (corrected to 15% O_2) when burning fuel oil.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest NO_x emission limit established to date for a combustion turbine is 4.5 ppmvd at 15% oxygen. This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system.

Selective catalytic reduction is a post-combustion method for control of NO_x emissions. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The SCR process can achieve up to 90% reduction of NO_x with a new catalyst. As the catalyst ages, the maximum NO_x reduction will decrease to approximately 86 percent.

The effect of exhaust gas temperature on NO_x reduction depends on the specific catalyst formulation and reactor design. Generally, SCR units can be designed to achieve effective NO_x control over a 100-300°F operating window within the bounds of 450-800°F, although recently developed zeolite-based catalysts are claimed to be capable of operating at temperatures as high as 950°.

Most commercial SCR systems operate over a temperature range of about 600-750°F. At levels above and below this window, the specific catalyst formulation will not be effective and NO_x reduction will decrease. Operating at high temperatures can permanently damage the catalyst through sintering of surfaces.

Increased water vapor content in the exhaust gas (as would result from water or steam injection in the gas turbine combustor) can shift the operating temperature window of the SCR reactor to slightly higher levels.

Although technically feasible, the applicant has rejected using SCR on the combined cycle because of economic, energy, and environmental impacts. The applicant has identified the following limitations:

a) Reduced power output.
b) Emissions of unreacted ammonia (slip).
c) Disposal of hazardous waste generated (spent catalyst).
d) Ammonium bisulfate and ammonium sulfate particulate emissions (ammonium salts) due to the reaction of NH_3 with SO_3 present in the exhaust gases.
e) The energy impacts of SCR will reduce potential electrical power generation of more than 7 million kwh per year.
f) Incremental cost effectiveness for the application of SCR technology to the Central Florida Power project was considered to be $7,400 per ton of NO_x removed.

Since SCR has been determined to be BACT for several combined cycle facilities, the EPA has clearly stated that there must be unique circumstances to consider the rejection of such control on the basis of economics.

In a recent letter from EPA Region IV to the Department regarding the permitting of a combined cycle facility (Tropicana Products, Inc.), the following statement was made:

> "In order to reject a control option on the basis of economic considerations, the applicant must show why the costs associated with the control are significantly higher for this specific project than for other similar projects that have installed this control system or in general for controlling the pollutant."

For fuel oil firing, the cost associated with controlling NO_x emissions must take into account the potential operating problems that can occur with using SCR in the oil firing mode.

A concern associated with the use of SCR on combined cycle projects is the formation of ammonium bisulfate. For the SCR process, ammonium bisulfate can be formed due to the reaction of sulfur in the fuel and the ammonia injected. The ammonium bisulfate formed has a tendency to plug the tubes of the heat recovery steam generator leading to operational problems. As this is the case, SCR has been judged to be technically infeasible for oil firing in some previous BACT determinations.

The latest information available now indicates that SCR can be used for oil firing provided that adjustments are made in the ammonia to NO_x injection ratio. For natural gas firing operation, NO_x emissions can be controlled with up to a 90 percent efficiency using a 1 to 1 or greater ammonia injection ratio. By lowering the injection ratio for oil firing, testing has indicated that NO_x can be controlled with efficiencies ranging from 60 to 80 percent. When the injection ratio is lowered there is not a problem with ammonium bisulfate formation since essentially all of the ammonia is able to react with the nitrogen oxides present in the combustion gases. Based on this strategy SCR has been both proposed and established as BACT for oil fired combined cycle facilities with NO_x emission limits ranging from 11.7 to 25 ppmvd depending on the efficiency of control established.

The applicant has indicated that the total levelized annual operating cost to install SCR for this project at 100 percent capacity factor and burning natural gas is $3,364,400 for the PG7221FA. Taking into consideration the total annual cost, a cost/benefit analysis of using SCR can now be developed.

For this project, based on the information supplied by the applicant, it is estimated that the maximum annual NO_x emissions using dry low-NO_x (natural gas) and water injection (oil firing) will be 702.1 tons/year (at 72°F). Assuming that SCR would reduce the NO_x emissions by 65%, about 245.7 TPY would be emitted annually. When this reduction (456.4 TPY) is taken into consideration with the total levelized annual operating cost of $3,364,400; the cost per ton of controlling NO_x is $7,400. This calculated cost is higher than has previously been approved as BACT.

A review of the latest DER BACT determinations show limits of 15 ppmvd (natural gas) using low-NO_x burn technology for combined cycle turbines. General Electric is currently developing programs using both steam/water injection and dry low NO_x combustor to achieve NO_x emission control level of 9 ppm when firing natural gas. Therefore, since this technology will likely be available by

1997, the Department has accepted the water/steam injection (for distillate fuel oil firing), the dry low-NO_x burner design, and the 25 ppmvd (natural gas)/42 ppmvd (oil) at 15% O_2 as BACT for a limited time (up to 12/31/97).

BACT Determination by DER

NO_x Control

The information that the applicant presented and Department calculations indicates that the cost per ton of controlling NO_x for this turbine [$7,400 per ton (natural gas)] is high compared to other BACT determinations which require SCR. Based on the information presented by the applicant, the Department believes that the use of SCR for NO_x control is not justifiable as BACT at this time.

A review of the permitting activities for combined cycle proposals across the nation indicates that SCR has been required and most recently proposed for installations with a variety of operating conditions (i.e., natural gas, fuel oil, and various capacity factors). Although, the cost and other concerns expressed by the applicant are valid, the Department, in this case, is willing to accept water/steam injection and low NO_x burner design as BACT for this project for a limited time (up to 12/31/97).

It is the Department's understanding that General Electric is developing programs for the PG7221FA using either steam/water injection or dry low NO_x combustor technology to achieve a NO_x emission control level of 9 ppm when firing natural gas.

Based on this, the Department has determined to revise and lower the allowable BACT limit for this project to 15 ppmvd at 15% O_2 no later than 12/31/97. For this turbine, an even lower NO_x emission level than 15 (gas)/42 (oil) ppmvd, corrected to 15% O_2, may become a condition of the permit pursuant to F.A.C. Rule 17-4.080.

CO Control

Combustion control will be considered as BACT for CO and VOC when firing natural gas.

Other Emissions Control

The emission limitations for PM and PM_{10}, Be, Pb, and Hg are based on previous BACT determinations for similar facilities.

The emission limits for the Central Florida Power, L.P. project are thereby established as follows:

258 MW COMBINED CYCLE COMBUSTION TURBINE
100 MMBtu/hr Duct Burner

Pollutant	Emission Standards/Limitations(a) Oil(b)	Gas(c)	Method of Control
NO_x (CT)	42 ppmvd at 15% O_2; 362.2 lbs/hr	25 ppmvd at 15% O_2; 161.9 lbs/hr	Water Injection/ Dry Low-NO_x Combustor
		15 ppmvd at 15% O_2; 97.2 lbs/hr	Dry Low-NO_x Combustor or any other NO_x Control Technology
NO_x (DB)		0.1 lbs/MMBtu	
CO (CT)	98.4 lbs/hr	49 lbs/hr	Combustion
CO (DB)		10 lbs/hr	
PM/PM_{10} (CT)	17 lbs/hr	9 lbs/hr	Combustion
PM/PM_{10} (DB)		0.01 lbs/MMBtu	
SO_2 (CT)	99.7 lbs/hr	4.9 lbs/hr	Distillate Fuel Oil (0.05% S)
SO_2 (DB)		0.3 lbs/hr	
H_2SO_4 (CT)	1.2 lbs/hr	5.95×10^{-1} lbs/hr	Distillate Fuel Oil (0.05% S)
H_2SO_4 (DB)		3.7×10^{-2} lbs/hr	
VOC (CT)	7.5 lbs/hr	2.8 lbs/hr	Combustion
VOC (DB)		2.9 lbs/hr	
Hg	3.0×10^{-6} lbs/MMBtu (5.5×10^{-3} lbs/hr)		Fuel Quality
Pb	8.9×10^{-6} lbs/MMBtu (1.65×10^{-2} lbs/hr)		Fuel Quality
Be	2.5×10^{-5} lbs/MMBtu (4.62×10^{-3} lbs/hr)		Fuel Quality
As	4.2×10^{-5} lbs/MMBtu (7.77×10^{-3} lbs/hr)		Fuel Quality

APPENDIX B

SAMPLE CALCULATIONS

SAMPLE CALCULATIONS

NO_x Emissions Corrected to 15% Oxygen

$$NO_x \text{ @ 15\% } O_2 = NO_x * ((20.9-15)/(20.9-O_2))$$

Where:

NO_x =   NOx concentration as measured in the sample gas in parts per million by volume (ppmV).

O_2 =   Oxygen concentration as measured in the sample gas by volume (%V).

NO_x @ 15% O_2 = NO_x concentration (ppmV) corrected to 15% oxygen.

Example: Run 1 7/21/93 - Unit 2

NO_x = 22.9 ppmV O_2 = 15.4%

NO_x @ 15% O_2 = 22.9 * ((20.9-15)/(20.9-15.4))
                     = 24.5

(Corrections for CO to 15% Oxygen are made in the same manner)

NO_x Emissions at 15% Oxygen and ISO Conditions

$$NO_{xISO} = NO_x \text{ @ 15\% } O_2 * (Pref/Pobs)^{0.5} * e^{19(Hobs-0.00633)} * (288/Tamb)^{1.53}$$

Where:

NO_x @ 15% O_2 = NO_x concentration (ppmV) corrected to 15% oxygen.
NO_{xISO} = NO_x concentration (ppmV) at 15% oxygen and ISO conditions.
Pref = Reference combustor inlet pressure (psia).
Pobs = Observed combustor inlet pressure (psia).
Hobs = Specific humidity of ambient air (lb H_2O/lb Dry Air)
       determined from the wet bulb and dry bulb readings and
       ASTM psychrometric eqn.
Tamb = Ambient temperature (K).

Example: Run 1 7/21/93 - Unit 2

NO_x @ 15% O_2 = 24.5 ppmV
Pbaro = 30.12" Hg * (14.696/29.92) = 14.794 psia
Pref = 125.99 psig +14.696 = 140.686 psia (see chart, Appendix D)
Pobs = 137.4 psig + Pbaro(14.794) = 152.19 psia
Hobs = 0.01114957 lb H_2O/lb DA
Tamb = (83.8 F - 32)*5/9 + 273 = 301.78 degrees K

NO_{xISO} = 24.5 $(140.686/152.19)^{0.5}$ $e^{19(0.01114957-0.00633)}$ $(288/301.78)^{1.53}$
               = 24.0 ppmV @ 15% O_2 and ISO conditions

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=====================================================================
■■■■       ■■■■■■■■■■■            0       Unit:   unit 2
=====================================================================
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VELOCITY AND VOLUMETRIC FLOWRATE DETERMINATION
EPA METHOD 2 CALCULATIONS

Parameter	Definition	Units
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Cp	- Pitot Tube Coefficient	Dimensionless
Vs	- Gas Stream Velocity	ft/sec
Qsd	- Volumetric Flow Rate at Standard Conditions,Dry Basis	dscfm
Qact	- Actual Volumetric Flow Rate, Wet Basis	acfm
Bws	- Moisture Content	mole fraction
Dp	- Avg. Sq. Root of Velocity Head	(in. H2O)^0.5
Pb	- Absolute Barometric Pressure	in. Hg
Kp	- Constant = 89.49 (ft)(lb/lb-mol)(in.Hg^0.5)/(s)((R)(in.H2O)	
Ts	- Absolute Gas Stream Temperature	degrees R
Ms	- Sample Gas Molecular Weight, Wet Basis	lb/lb-mole
Sp	- Static Pressure of Gas Stream	in. H2O
528	- Absolute Standard Temperature	degrees R
CSA	- Stack Cross-Sectional Area	ft2
Ps	- Absolute Stack Gas Pressure	in. Hg
60	- Conversion Factor	sec/min.
Pi	- Constant Ratio - 3.1416	Dimensionless
D	- Duct Diameter	inches

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=====================================================================
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TEST DATA RUN #2-1

Ms	=	28.526	Cp	=	0.84
Bws	=	0.0536	Pb	=	30.15
Sp	=	-1.60	Ts	=	1444.7
D	=	222.00	Dp	=	1.1412

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=====================================================================
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Circular Duct

$$Ps = Pb + (Sp/13.6) = 30.15 + (-1.60/13.6) = 30.03 \text{ in.Hg}$$

$$Vs = (85.49)(Cp)(Dp)*[(Ts)/(Ms*Ps)]^{0.5}$$

$$= 85.49*0.84*1.1412*[1444.7/(28.526*30.03)]^{0.5}$$

$$= 106.421 \text{ ft/s} \qquad\qquad 106.421 \text{ ft/s}$$

$$CSA = (Pi)[(D)^2]/[(4)(144)] = 3.1416*(222.00^{0.5})/(4*144) \quad 268.803 \text{ ft2}$$

$$Qact = (Vs)*CSA*60 = 106.421*268.803*60 = 1716377. \text{ acfm}$$

$$Qsd = \frac{(Qact)(1-Bws)(528)(Ps)}{(Ts)(29.92)} = \frac{1716377.3*(1 - 0.0536)*528*30.03}{1444.7*29.92}$$

$$= 595883.4 \text{ dscfm} \qquad\qquad 595883.4 \text{ dscfm}$$

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------------------------------------------------------------------
████████       ████████████            0      Unit:    unit 2
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MOLECULAR WEIGHT DETERMINATION
EPA METHOD 3 CALCULATIONS

Parameter	Definition	Units
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Md	- Sample Gas Molecular Weight, Dry Basis	lb/lb-mole
Ms	- Sample Gas Molecular Weight, Wet Basis	lb/lb-mole
Bws	- Moisture Content	mole fraction
%CO2	- Carbon Dioxide Concentration, Dry Basis	% Volume
%CO	- Carbon Monoxide Concentration, Dry Basis	% Volume
%O2	- Oxygen Concentration, Dry Basis	% Volume
%N2	- Nitrogen Concentration, Dry Basis (gas balance)	% Volume
0.32	- Molecular Weight of Oxygen (O2), divided by 100%	lb/lb-mole
0.28	- Molecular Weight of Carbon Monoxide, divided by 100%	lb/lb-mole
0.28	- Molecular Weight of Nitrogen (N2), divided by 100%	lb/lb-mole
0.44	- Molecular Weight of Carbon Dioxide, divided by 100%	lb/lb-mole
18.0	- Molecular Weight of Water	lb/lb-mole

```
------------------------------------------------------------------
                  TEST DATA RUN #2-1


      Bws =       0.0536        %CO =       0.00
      %N2 =       81.43         %CO2 =      3.17
      %O2 =       15.40


------------------------------------------------------------------
```

$$Md = (0.44)(\%CO2) + (0.32)(\%O2) + (0.28)(\%N2 + \%CO)$$

$$= (0.44)*3.17 + (0.32)*15.40 + (0.28)*(81.43 + 0.00)$$

$$= 29.123 \text{ lb/lb-mol}$$

$$Ms = (Md)(1 - Bws) + (18.0)(Bws)$$

$$= 29.123*(1 - 0.0536) + 18.0*0.0536$$

$$= 28.526 \text{ lb/lb-mol}$$

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========================================================================
███████      ██████████████            0       Unit:   unit 2
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MOISTURE CONTENT DETERMINATION
EPA METHOD 4 CALCULATIONS

Parameter	Definition	Units
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```

Pm - Absolute Meter Pressure — in. Hg
Po - Average Meter Differential Pressure — in. H2O
Ps - Absolute Stack Gas Pressure — in. Hg
Pstd - Absolute Standard Barometric Pressure (29.92) — in. Hg
Pb - Absolute Barometric Pressure — in. Hg
K   - Standard Volume H2O Vapor/Unit Weight Liquid — ft3/g
      Constant = 0.04715 cu.ft/g
Tm - Average Meter Temperature — degrees R
Tstd - Absolute Standard Temperature (528[R]) — degrees R
DGMC - Dry Gas Meter Correction Factor (gamma) — Dimensionless
Vlcg - Total Condensate Collected — grams H2O
Vm - Metered Dry Sample Gas Volume — dcf
Vmstd - Metered Volume at Standard Conditions(528[R, 1atm) — dscf
Vwstd - Volume of Water Vapor Collected, at Standard — scf
        Conditions (528[R, 1atm)
W(sat)- Vapor Pressure of H2O at Stack Temperature — in. Hg
Bws   - Moisture Content — mole fraction
Bwd   - Moisture Content — % Volume

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```

TEST DATA RUN #2-1

Pb =	30.15	Tm =	551.3
Vm =	44.124	Po =	1.66
Vlcg=	50.8	DGMC =	0.9887
W(sat)=	30.15	Ps =	30.03235

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MEASURED MOISTURE CALCULATIONS

$$Pm = Pb + (Po/13.6) = 30.15 + (1.66/13.6) = 30.272 \text{ in. Hg}$$

$$Vmstd = \frac{(Vm)(DGMC)(Pm)(Tstd)}{(Pstd)(Tm)} = \frac{44.124 \cdot 0.9887 \cdot 30.27 \cdot 528}{29.92 \cdot 551.3} = 42.273 \text{ ft3}$$

$$Vwstd = (K)(Vlcg) = (0.04715) \cdot (50.8) = 2.395 \text{ ft3}$$

$$Bws = (Vwstd)/\{(Vwstd)+(Vmstd)\} = 2.395/(2.395+42.273) = 0.0536 \text{ mol frac}$$

$$Bwd = (Bws) \cdot 100 \% = 0.0536 \cdot 100\% = 5.36\%V$$

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========================================================================
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SATURATED MOISTURE CALCULATIONS

$$B(sat) = W(sat)/Ps = 30.15/30.03 = 1.003917 \text{ mol frac}$$

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========================================================================
```

VAPOR PHASE MOISTURE

Bws = 0.053622   Lower of Measured or Saturated Moisture

RELATIVE ACCURACY CALCULATIONS

Arithmetic Mean: Calculate the arithmetic mean of the difference, d, of a data set as follows.

$$\bar{d} = \frac{1}{n} \sum_{i=1}^{n} d_i$$

where

n — number of data points

$$\sum_{i=1}^{n} d_i = \text{Arithmetic sum of the individual differences } d_i$$

Standard Deviation: Calculate the standard deviation, S_d as follows:

$$S_d = \left[\frac{\sum_{i=1}^{n} d_i^2 - \left(\frac{\sum_{i=1}^{n} d_i}{n}\right)^2}{n-1}\right]^{1/2}$$

Confidence Coefficient: Calculate the 2.5 percent error confidence coefficient (one-tailed), CC, as follows:

$$CC = t_{0.975} \frac{S_d}{\sqrt{n}}$$

where $t_{0.975}$ — t-value (see Table 1)

Relative Accuracy: Calculate the RA of a set of data as follows:

$$RA = \frac{|\bar{d}| + |CC|}{\overline{RM}} \times 100$$

where

$|\bar{d}|$ — Absolute value of the mean of differences

$|CC|$ — Absolute value of the confidence coefficient

$\overline{RM}$ — Average reference method value or applicable standard

TABLE 1   t-VALUES

n^*	$t_{0.975}$	n^*	$t_{0.975}$	n^*	$t_{0.975}$
2	12.706	7	2.447	12	2.201
3	4.303	8	2.365	13	2.179
4	3.182	9	2.306	14	2.160
5	2.776	10	2.262	16	2.145
6	2.571	11	2.228	16	2.131

*The values in this table are already corrected for n-1 degrees of freedom. Use n equal to the number of individual values.

APPENDIX C

EXAMPLE DATA SHEETS,

AND CALIBRATION DATA SHEETS

EPA METHOD 1
TRAVERSE POINT LAYOUT

ESE Environmental Science & Engineering, Inc.

CLIENT:	
PROJECT NUMBER:	
SOURCE I.D.:	
DATE:	
INSIDE DIAMETER:	in
UPSTREAM DISTANCE (A):	in
DOWNSTREAM DISTANCE (B):	in
COUPLING LENGTH:	in
NUMBER OF PORTS:	
UPSTREAM DIAMETERS:	
DOWNSTREAM DIAMETERS:	
CALCULATED BY:	

DISTURBANCE

A

MEASUREMENT SITE

B

STACK DIAGRAM

DISTURBANCE

TRAVERSE POINT	TRAVERSE % DIAMETER		INSIDE DIAMETER		COUPLING LENGTH		TRAVERSE LOCATION
1		X		+		=	
2		X		+		=	
3		X		+		=	
4		X		+		=	
5		X		+		=	
6		X		+		=	
7		X		+		=	
8		X		+		=	
9		X		+		=	
10		X		+		=	
11		X		+		=	
12		X		+		=	

COMMENTS: _____
_____
_____
_____

(English units)

Date _____   Meter box number _____

Barometric pressure, P_b = _____ in. Hg   Calibrated by _____

| Orifice manometer setting (ΔH), in. H_2O | Gas volume | | Temperatures | | | | Time (θ), min | Y_i | ΔH@$_i$ in. H_2O |
| | Wet test meter (V_w), ft^3 | Dry gas meter (V_d), ft^3 | Wet test meter (t_w), °F | Dry gas meter | | | | | |
				Inlet (t_{d_i}), °F	Outlet (t_{d_o}), °F	Avg[a] (t_d), °F			
							Avg		

ΔH, in. H_2O	$\dfrac{\Delta H}{13.6}$	$Y_i = \dfrac{V_w\, P_b\,(t_d + 460)}{V_d\left(P_b + \frac{\Delta H}{13.6}\right)(t_w + 460)}$	$\Delta H@_i = \dfrac{0.0317\ \Delta H}{P_b\,(t_d + 460)}\left[\dfrac{(t_w + 460)\ \theta}{V_w}\right]^2$

[a] If there is only one thermometer on the dry gas meter, record the temperature under t_d.

ESE ISOKINETIC SAMPLING FIELD DATA SHEET

Facility:		Meter #:		Baro. Press.:		
Unit:		DH@		Ambient T:		
Location:		DGM Factor:		Nozzle Dia:		
Test Type:		Pitot #:		Static P:		
Run #:		Pitot Coef:		Stack Dimensions:		
Operator(s):		K−Factor:		Initial Leak Check:	cfm @	"Hg
Date:		Filter #:		Final Leak Check:	cfm @	"Hg

Traverse Point Number	Time	Gas Meter Reading Vm(ft3)	Velocity Head ("H2O)	Orifice Press. ("H2O)	Stack Temp. (F)	Probe Temp. (F)	Filter Temp. (F)	Impinger Temp. (F)	Dry Gas Meter Temp.		Vacuum ("Hg)
									Inlet (F)	Outlet (F)	
Avg/Tot.											

Impinger	1	2	3	4	5	Total	Orsat	1	2	3	4
Initial							O2				
Final							CO2				
Total											

CALIBRATION SUMMARY
07-21-1993   06:38:25
CALIBRATION FILE NAME =c:\cexdata\PPLUS.CAL

```
=====================================================================
Chan. Name Units |    Zero     |    Span     |  Slope    Int.
               | Conc.  Resp. | Conc.  Resp. |
=====================================================================
  1   O2   %V    0.00   0.0004   20.90  0.085   246.248   -0.11
  2   CO   ppmV  0.00   0.0282   92.50 -9.223   -10.032    0.28
  3   NOx  ppmV  0.00   0.0084   92.90  8.085    11.502   -0.10
  4   NULL       0.00   0.0000    0.00  0.000     1.000    0.00
  5   CO   ppm15 0.00   0.0000    0.00  0.000     1.000    0.00
  6   NOx  ppm15 0.00   0.0000    0.00  0.000     1.000    0.00
  7   NOx  ISD   0.00   0.0000    0.00  0.000     1.000    0.00

=====================================================================
```

Press Shift-PrtSc to Print Out Table
Press (C) to Continue

~ronmental Science & Engineering   RUN 2
~s Emissions Testing Dept.   Tdb= 82.5
~inuous Emissions Monitoring Data   T.b= 65.4
                                              Hobs= 1.099953E-02
                                              Baro= 30.12
~sed for: Pref 125.99
: Printed = 07-21-1993 Current Time = 18:27:45   Pobs= 137.5
  Name = c:\ceedata\072193.PRN   Calibration File:c:\ceedata\DFLUD.CAL

| ~1-1993 | O2 | CO | NOx | NULL | CO | NOx | NOx |
	%V	ppmV	ppmV		ppm15	ppm15	ISO
17:53	15.3	-0.4	22.9	-0.4	-0.4	24.4	23.9
8:23	15.4	-0.5	23.0	-0.4	-0.5	24.5	24.0
8:53	15.4	-0.4	23.1	-0.4	-0.4	24.6	24.1
9:23	15.4	-0.4	23.0	-0.4	-0.4	24.5	24.0
19:53	15.4	-0.5	22.9	-0.4	-0.5	24.5	24.0
20:23	15.4	-0.4	23.0	-0.4	-0.4	24.5	24.0
0:53	15.4	-0.4	22.9	-0.4	-0.4	24.4	23.9
21:23	15.4	-0.4	22.9	-0.4	-0.5	24.5	24.0
21:53	15.4	-0.4	22.9	-0.4	-0.4	24.5	23.9
2:23	15.4	-0.4	22.9	-0.4	-0.5	24.5	24.0
2:53	15.4	-0.4	22.9	-0.4	-0.4	24.5	24.0
23:23	15.4	-0.4	22.8	-0.4	-0.4	24.4	23.9
23:53	15.4	-0.4	22.8	-0.4	-0.4	24.4	23.9
4:23	15.4	-0.4	22.8	-0.4	-0.4	24.4	23.9
24:53	15.4	-0.4	22.9	-0.4	-0.4	24.5	24.0
25:23	15.4	-0.4	23.0	-0.4	-0.4	24.6	24.1
5:53	15.4	-0.4	22.9	-0.4	-0.5	24.5	24.0
6:23	15.4	-0.4	22.9	-0.4	-0.4	24.5	24.0
26:53	15.4	-0.4	22.8	-0.4	-0.5	24.4	23.9
27:23	15.4	-0.4	23.0	-0.4	-0.4	24.6	24.1
7:53	15.4	-0.4	22.9	-0.4	-0.5	24.5	24.0
28:23	15.4	-0.4	22.9	-0.4	-0.4	24.5	24.0
28:53	15.4	-0.4	22.9	-0.4	-0.4	24.5	24.0
9:23	15.4	-0.4	22.7	-0.4	-0.4	24.3	23.8
9:53	15.4	-0.4	22.8	-0.4	-0.5	24.4	23.9
40:23	15.4	-0.4	22.8	-0.4	-0.4	24.4	23.9
40:53	15.4	-0.5	22.9	-0.4	-0.5	24.5	24.0
1:23	15.4	-0.4	22.9	-0.4	-0.4	24.5	24.0
41:53	15.4	-0.4	22.9	-0.4	-0.4	24.4	23.9
42:23	15.4	-0.4	22.7	-0.4	-0.4	24.3	23.8
2:53	15.4	-0.4	22.9	-0.4	-0.4	24.4	23.9
3:23	15.4	-0.4	22.9	-0.4	-0.4	24.5	24.0
43:53	15.4	-0.4	23.1	-0.4	-0.5	24.7	24.2
44:23	15.4	-0.4	22.9	-0.4	-0.4	24.4	23.9
4:53	15.4	-0.4	23.0	-0.4	-0.4	24.5	24.0
45:23	15.4	-0.5	22.9	-0.4	-0.5	24.4	23.9
45:53	15.4	-0.5	23.0	-0.4	-0.5	24.6	24.1
6:23	15.4	-0.5	23.0	-0.4	-0.5	24.6	24.1
6:53	15.4	-0.4	22.9	-0.4	-0.4	24.5	24.0
47:23	15.4	-0.4	23.0	-0.4	-0.4	24.7	24.2
47:53	15.4	-0.4	23.0	-0.4	-0.4	24.6	24.1
8:23	15.4	-0.4	23.0	-0.4	-0.5	24.6	24.1
48:53	15.4	-0.4	23.0	-0.4	-0.4	24.6	24.1
49:23	15.4	-0.4	22.9	-0.4	-0.5	24.6	24.1
9:53	15.4	-0.4	23.0	-0.4	-0.4	24.6	24.1
0:23	15.4	-0.5	22.9	-0.4	-0.5	24.6	24.0

```
7-21-1993  O2    CO    NOx   NULL   CO    NOx   NOx
Time       %     ppm   ppmW         ppm15 ppm15 TPD

=======================================================================================

9:50:53   15.4  -0.4  23.0  -0.4  -0.5  24.6  24.1
9:51:23   15.4  -0.4  22.9  -0.4  -0.4  24.5  24.1
9:51:53   15.4  -0.4  22.9  -0.4  -0.4  24.5  24.0
9:52:23   15.4  -0.5  22.9  -0.4  -0.5  24.6  24.1
9:52:53   15.4  -0.5  22.9  -0.4  -0.5  24.7  24.2
9:53:23   15.4  -0.4  22.8  -0.4  -0.5  24.6  24.1
9:53:53   15.4  -0.5  22.8  -0.4  -0.5  24.4  23.9
9:54:23   15.4  -0.4  22.9  -0.4  -0.4  24.5  24.0
9:54:53   15.4  -0.4  22.8  -0.4  -0.4  24.4  23.9
9:55:23   15.4  -0.4  22.8  -0.4  -0.5  24.4  23.9
9:55:53   15.4  -0.4  22.9  -0.4  -0.5  24.5  24.0
9:56:23   15.4  -0.4  22.8  -0.4  -0.4  24.4  23.9
9:56:53   15.4  -0.4  22.7  -0.4  -0.4  24.4  23.9
9:57:23   15.4  -0.4  22.8  -0.4  -0.4  24.5  24.0

=======================================================================================

Avg.=     15.4  -0.4  22.9  -0.4  -0.5  24.5  24.0

=======================================================================================
```

INSTRUMENTATION RESPONSE TIME WORKSHEET

ESE Environmental Science & Engineering, Inc.

CLIENT:	PROJECT NO.:
FACILITY:	ANALYST:
SOURCE I.D. NO.:	DATE:

INSTRUMENT SPECIFICATIONS

ANALYZER:		
MODEL NO.:		
SPAN RANGE:		
SPAN GASES:		
CHART SPEED:		

RESPONSE TIME DATA

UPSCALE RESPONSE		
☐ SECONDS		
☐ MINUTES		
AVERAGE		
DOWNSCALE RESPONSE		
☐ SECONDS		
☐ MINUTES		
AVERAGE		

COMMENTS:

REFERENCE METHOD
ANALYZER CALIBRATION RECORD

Instrument: _____   Range: _____

Date: _____   Fuel: Gas / Oil

Operator: _____   Units: %V / ppmV

Run #	Time	Load	Certified Gas Conc.	Observed Gas Conc.	Difference	Difference Percent of Scale
MP 1		NA	Zero: 0			
MP 2		NA	High:			
MP 3		NA	Mid:			
MP 4		NA	Low:			

Comments: MP = Multi-Point Calibration.

EXAMPLE RELATIVE ACCURACY FIELD DATA SHEET

Run No.	Date and time	SO$_2$			NO$_x$[b]			CO$_2$ or O$_2$[a]		SO$_2$[a]			NO$_x$[a]		
		RM	M	Diff	RM	M	Diff	RM	M	RM	M	Diff	RM	M	Diff
		ppm[c]			ppm[c]			%[c]	%[c]	mass/GCV			mass/GCV		
1															
2															
3															
4															
5															
6															
7															
8															
9															
10															
11															
12															
Average															
Confidence Interval															
Accuracy															

Make sure that RM and M data are on a consistent basis, either wet or dry.